Alberta
ENERGY

Petroleum Plaza – North Tower
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06-11

GAS ROYALTY CALCULATION INFORMATION BULLETIN
November 2006

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PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for September 2006, refer to Attachments 1, 1A, 2, 2A, and 3.

B. NOTICES

To provide further clarification the following article has been modified from the original publication in the October 2006 Information Bulletin.

Termination of the Deep Gas Royalty Holiday Program (DGRHP) and Implementation of a new Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW)

On August 22, 2006, Alberta Energy (DOE) announced the termination of the existing royalty holiday program for deep natural gas wells and the implementation of a new adjustment program for deep marginal natural gas wells as described in Information Letter 2006-26. The changes are effective as of September 1, 2006.

Phasing out the existing Deep Gas Royalty Holiday Program (DGRHP)
Wells that are drilled or deepened, before April 1, 2010, on a Crown Agreement that has a term commencement date (the date the mineral rights were acquired from the Crown) earlier than September 1, 2006 and meets the DGRHP criteria will continue to be eligible for exemption under the existing DGRHP, with the following exceptions:

- Oil and oil sands wells, which are spudded or commence drilling on or after September 1, 2006, are no longer eligible for exemption under the DGRHP.
- Commencing April 1, 2012 all wells that have remaining benefits under the DGRHP will have the benefits rolled into the new program, and will be subject to a minimum 5% royalty rate.

Clients who are eligible for an exemption under the DGRHP may elect to receive adjustments under the new Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW) rather than receive an exemption under the DGRHP. The election must be made in writing by the Designated Representative identified on the Crown Agreement or by the well licensee prior to spudding or commencement of drilling and sent to:

Attention:
Gas Royalty Calculation Unit
Royalty Programs
8th floor NPP
9945 - 108 Street
Edmonton, AB T5K 2G6

The election must include the Crown Agreement number, the term commencement date and the legal land description. If a well license has been issued by the Alberta Energy and Utilities Board (EUB) the license number and the unique well identifier must also be included. In those situations where the well information is not available at the time of election, the Designated Representative or well licensee/operator must supply the well event identifier when it is available. The department will provide written notification regarding the well's eligibility.

New Program: Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW)

Highlights of Program

- The royalty adjustment begins on the first day of the month in which the royalty payable on gas production obtained from the well is due.
- Royalty adjustments must be used within 10 years following the finished drilling date applicable to the drilling or deepening of the well and will terminate if the well is abandoned.
- Wells are subject to a minimum 5% royalty rate each month.
- Royalty adjustments are limited to a maximum of $3,600,000 per well regardless of the number of producing zones.
- Determination of the royalty adjustment amount is based on the vertical and non-vertical (e.g. horizontal) depth of the well.
- Wells are subject to a production threshold.

Qualifying Criteria

To receive royalty adjustments under the RAPDMGW a well must:

- Be drilled or commence drilling on a Crown Agreement with a term commencement date on or after September 1, 2006,
- For Crown lands acquired prior to September 1, 2006, an election, as described above, may be made to qualify the well for this adjustment instead of a benefit under the DGRHP,
- Be drilled or deepened in a drilling spacing unit which is wholly outside the pool boundaries as designated by the EUB as at June 1, 1985 (i.e. outside an existing G-order),
- Be drilled into a producing zone, the top of which has a vertical depth greater than 2,500 meters,
- Not have average daily production (ADP) that exceeds the qualifying production rate (QPR) during each 12 month reporting period at any point during the adjustment entitlement. The first 12 month period commences on the effective date of the adjustment.

Wells that do not qualify for RAPDMGW include:

- A well completed in a drilling spacing unit containing wells that previously received a royalty exemption or royalty adjustment under prior regulations or Sections 10 -11 of Schedule 8 of the *Natural Gas Royalty Regulations, 2002*,
- A well whose production of crude oil or oil sands is exempt from royalty under the *Third Tier Exploration Well Royalty Exemption Regulation* and that exemption has not wholly been revoked,
- Off target wells,
- A well that produces oil either alone, or with gas at a gas-oil ratio of less than 1800:1,
- A well that produces oil sands, other than a gas well as defined in the *Oil and Gas Conservation Regulations.*

Determining whether a well qualifies

The process and technical analysis of whether a well qualifies for RAPDMGW will be completed in the same manner as DGRHP wells. An application is not required. If the department determines that the well meets all of the qualifying criteria, except the QPR, the department will perform a preliminary calculation of the ADP using available well production data at that time and compare this against the QPR described below.

If the ADP is below the calculated QPR at the initial calculation, the well will tentatively be approved for royalty adjustment under the program. A calculation of the QPR using production data for the 12 month reporting period will be completed when the data is available.

The calculation of the Average Daily Production (ADP) & Qualifying Production Rate (QPR)

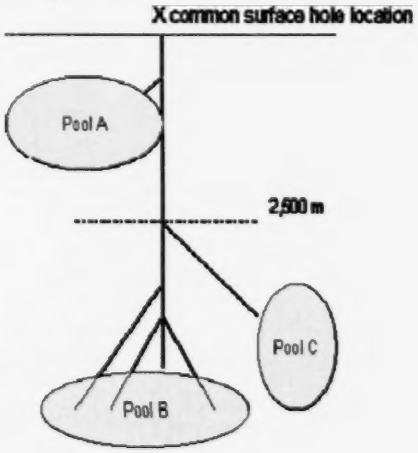
The ADP is determined by dividing the quantity of natural gas and field condensate from all the drilling occurrences that share the same surface location (production from all zones in a multi-zone well bore) within the 12 month reporting period and dividing this quantity by the number of days in the period (note these are not operating days but calendar days).

Note: Field condensate volumes will be expressed as a gas equivalent volume using a conversion rate of 1,000 cubic meters of natural gas per cubic meter of condensate.

The QPR will continue to be re-calculated, each reporting period for all non-statute barred years, for the entire 10 year entitlement period for the well regardless of whether the entire adjustment has been taken. If at any point the ADP exceeds the QPR, the entire adjustment will be revoked.

As shown in the diagram below the production included in the determination of the ADP would include all the drilling occurrences (each leg from the initial well is considered a drilling occurrence) that share this common surface hole location.

Diagram 1



The QPR was established to reference an economic threshold for wells at varying depths. For the initial six month analysis and first 12 month period the QPR is based on the following formula:

For wells drilled > 2,500 m but ≤ 3,500 m

$$QPR = \left[1.1327e^{3}m^{3} + \left\{ .0850e^{3}m^{3} \times \frac{(MD - 2500m)}{100m} \right\} \right] \times \left[\frac{MD}{100m} \right] \leq 3500 \text{ m}$$

For wells drilled > 3,500 m

$$QPR = \left[1.9822e^{3}m^{3} + \left\{ 0.1133e^{3}m^{3} \times \frac{(MD - 3500m)}{100m} \right\} \right] \times \left[\frac{MD}{100m} \right] > 3500 \text{ m}$$

Where:
QPR = the qualifying production rate for the well
MD = the measured depth of the well on the last day of the applicable period

The QPR for the second 12 month period will be 80% of the first period QPR and 68% of the first period QPR for the third and all subsequent 12 month periods.

If a well has an acid gas content of more than 15% by volume, the QPR may be adjusted using the following formula:

Adjusted QPR = QPR / [100% - (H_2S% + CO_2% - 15%)]

Where:
QPR = the qualifying production rate for the well
H_2S and CO_2 = the % of hydrogen sulphide and carbon dioxide contained in the raw gas stream by volume, respectively.

In cases where the well operator/licensee is seeking to have the adjusted QPR applied, it is their responsibility to provide documentation for the department's review, such as a gas analysis report signed by a professional engineer.

Determination of Royalty Adjustment
The royalty adjustment is the sum of the vertical and non-vertical adjustments. These adjustments are based on the corresponding vertical and non-vertical depths of the well, which are determined as follows.

The vertical depth is determined by using the distance from the surface location Kelley bushing to the shallower of the deepest point of the well or to the base of the natural gas producing interval in the deepest zone in paying quantities. The vertical depth, below 2,500 meters, is used in calculating the vertical adjustment as shown in Attachment 4.

The measured depth is the longest distance in meters measured along the well bore from the Kelley bushing to the lesser of the longest point of the well or to the base of a natural gas producing interval that is producing in paying quantities.

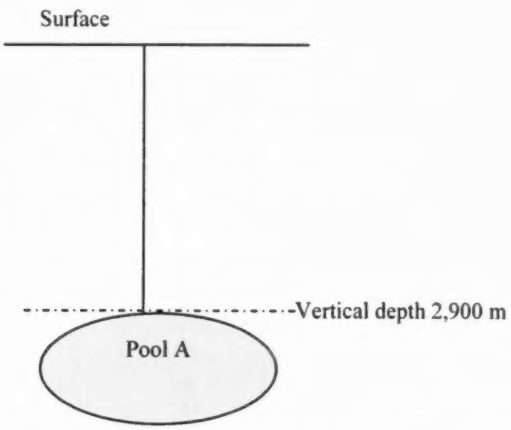
The non-vertical depth is the measured depth less the vertical depth of the well. The non-vertical depth is multiplied by $1000 per meter to determine the non-vertical adjustment.

A well that did not qualify for an adjustment previously but is subsequently deepened will be treated as a new well. In the case of an existing well that has received an adjustment and is subsequently deepened, a modified adjustment will be determined and a new initial QPR will be established.

The provincial weighted average gross up factor of 1.72392 will be applied against the adjustment amount determined by the formula above.

The following illustrations depict how the vertical depth, measured depth and non-vertical depth of wells are determined for the purpose of calculating an adjustment value.

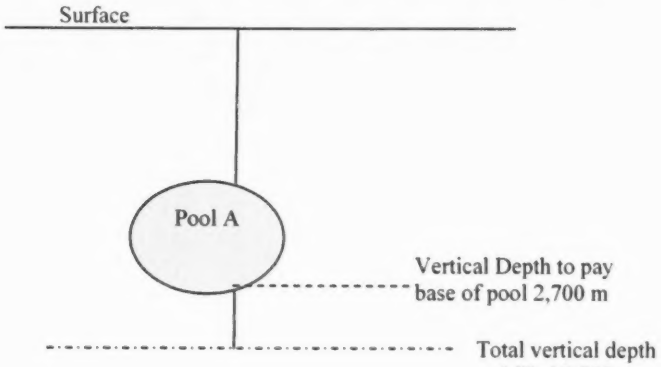
Figure 1 – Vertical well



Vertical depth = 2,900 m
Measured depth = 2,900 m
Non-vertical depth = 0

Vertical adjustment:
2,500 m = 0
400 m x $1,000 = $400,000
Non-vertical adjustment = $0
Total adjustment = $400,000

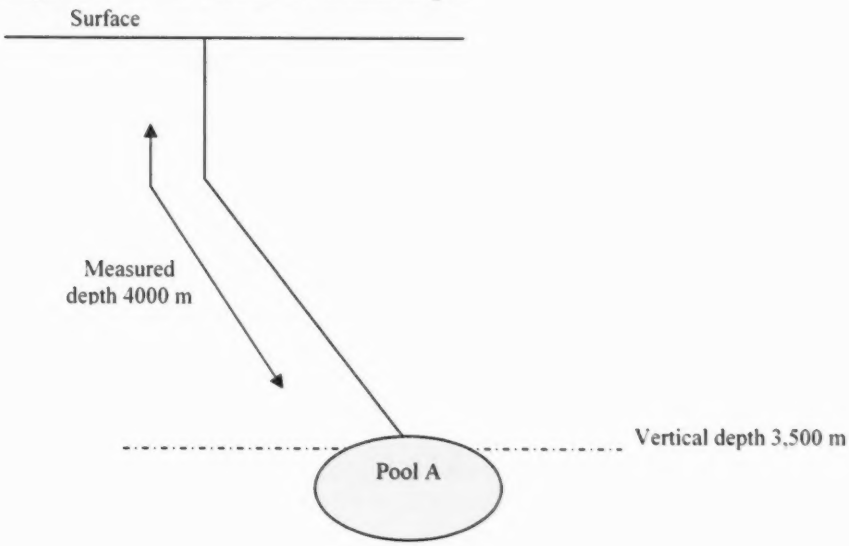
Figure 2 – A vertical well that extends past the pay base of the pool



Vertical depth = 2,700 m
Measured depth =2,700 m
Non-vertical depth = 0

Vertical adjustment:
2,500 m = $0
200 m x $1,000 = $200,000
Non-vertical adjustment = $0
Total adjustment = $200,000

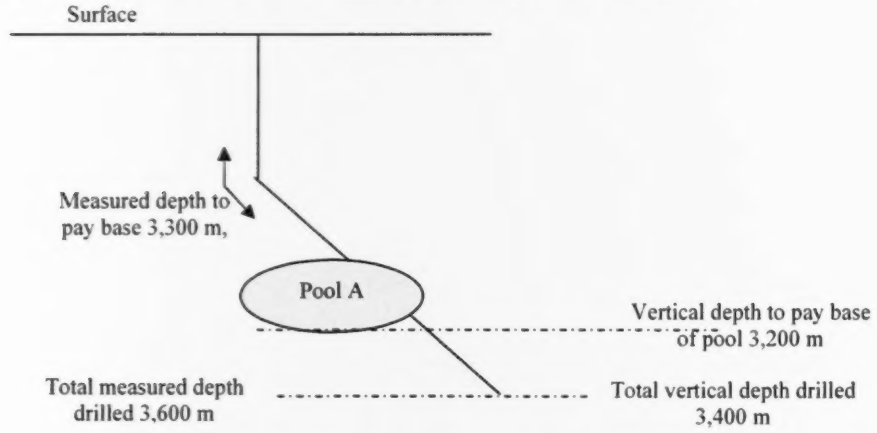
Figure 3 – Well with non-vertical depth



Vertical depth = 3,500 m
Measured depth = 4,000 m
Non-vertical depth = 500 m

Vertical adjustment:
3,500 m = $1,000,000
Non-vertical adjustment:
500 m x $1,000 = $500,000
Total adjustment = $1,500,000

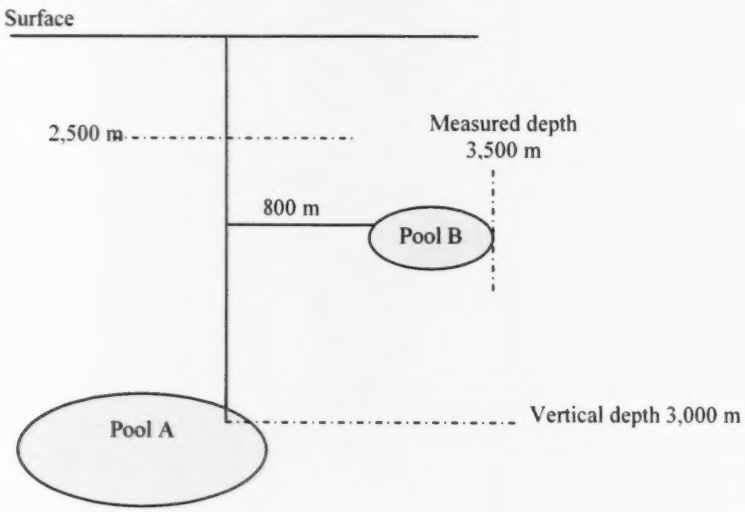
Figure 4 – Measured depth extends past the pay base of the pool


Surface
Measured depth to pay base 3,300 m,
Pool A
Vertical depth to pay base of pool 3,200 m
Total measured depth drilled 3,600 m
Total vertical depth drilled 3,400 m

Vertical depth = 3,200 m
Measured depth =3,300 m
Non-vertical depth = 100 m

Vertical adjustment:
3,000 m = $500,000
200 m x $1,000 = $200,000
Non-vertical adjustment:
100 m x $1,000 = $100,000
Total adjustment = $800,000

Figure 5 – Multi well bore



Vertical depth = 3,000 m
Measured depth = 3,500 m
Non-vertical depth = 500 m

Vertical adjustment:
3,000 m = $500,000
Non-vertical adjustment:
500 m x $1,000 = $500,000
Total adjustment = $1,000,000

Revocation of Royalty Adjustment if QPR exceeded
If at any point during the royalty adjustment entitlement period the ADP of the well exceeds the calculated QPR, the royalty adjustment will be revoked. The effective date of the revocation will be the royalty adjustment commencement date unless the well has been deepened after this date and the excess production is a result of the deepening. In this case the effective date for revocation will be the date the well was deepened.

Any Crown royalty charges that were offset by the adjustment will be reversed and royalty payable on the natural gas, field condensate and gas products will be recalculated as if the royalty adjustment never arose. Interest will apply to the recalculation of royalties.

If a royalty adjustment is revoked because the QPR was exceeded, a royalty client may request a review and must provide supporting documentation (e.g. Gas analysis report). The department will review the documentation and determine whether the royalty adjustment will be reinstated.

Processing time lines
The time line for processing royalty adjustments will be similar to those for the DGRHP. The department will inform the operator and licensee in writing when the well qualifies, the royalty adjustment amount, and other pertinent data. Clients may also track the progress of eligible wells on the internet through a well 'process status' spreadsheet similar to the spreadsheet for the DGRHP. See the Natural Gas Royalty Guidelines, 2006, Chapter V, Section 1 for a complete description of the available "process statuses."

Reporting
The department determines the monthly royalty adjustment amount based on the volumetric production and SAF/OAF allocation reporting. In order for a royalty adjustment to be applied against a well, the well must be reported at a single well level, except in the case where only a portion of the well qualifies for a royalty adjustment. In these situations the department will advise clients how to report the production.

Invoices/Statements
The department will automate the processes relating to this program in the near future. Until such time, the following processes will apply:

- In the first billing period, relating to the production reported for the well, the 5% royalty will not be charged. There will be a one month lag.
- In the following billing period the minimum 5% royalty rate will be calculated and charged. Interest will be charged on underpayments of royalties.
- RAPDMGW wells will appear on the royalty exemption statement as DGRHP wells. The remaining royalty adjustment balance shown on the exemption statement will be overstated by the 5% royalty which was not charged in the first billing period.
- Monthly, the department will send out a revised statement to all participants in the well showing the actual remaining royalty adjustment balance.

For additional information, please contact RoseAnn Summers, Manager, Royalty Billing at (780) 422-6684 or Tracy Wadson, Team Lead, Royalty Programs at (780) 422-9240. Email inquiries can be directed to RoyaltyPrograms@gov.ab.ca

Expected AC2 Reports on the Registry

Expected capital cost allowance (AC2) reports will be sent directly to the Registry early in 2007. The reports will be available in PDF, TXT, and CSV format. If you are not a Registry user the report will be mailed to you as in previous years. The dates the expected capital cost allowance report will run are not available, but a Bulletin update will be published when the dates have been confirmed.

Should you have any questions or concerns regarding AC2 filings or the reports, please contact your Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin or Joey Dennis at (780) 422-9260.

Allowable Costs Training

Client Services is planning to have a training session in Calgary in March 2007. The subject for this session will be allowable costs and we would like to get some feedback from industry as to what you would like to see in the content of this session and how many people from your company might attend. Please call or e-mail Gas Royalty Client Services with your requests or information on attendees. See Section F for contact information.

Times and location for this session will be announced early in the new year.

Office Closures – Christmas Period

All Alberta Energy offices will be closed from Monday, December 25 to Wednesday, December 27, 2006 inclusive. Our offices are also closed on Monday, January 1, 2007.

C. MONTHLY INFORMATION

September 2006 Royalty Due December 31

- **Royalty clients are to remit the total amount payable shown on the December 2006 Statement of Account by December 31, 2006.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The December 2006 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your September 2006 Invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of September 2006 if it is paid in full by December 31, 2006.

- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

Note: If the due date falls on a non-business day, the next business day will apply as the due date.

- Cheques are payable to the Minister of Finance, Province of Alberta.

October 2006 VA4 Due December 15

The VA4 forms for the production month of October 2006 are due in the department offices by December 15, 2006.

Note: If the due date (15th) falls on a non-business day, the next business day will apply as the due date for VA4 forms.

October 2006 Production Reporting

October 2006 production reporting is submitted through the Registry. The deadline for submission of SAF, OAF, and Volumetrics is posted in the Petroleum Registry of Alberta website "Reporting Calendars" under Bulletin Board.

Changes to this calendar will be posted on the Registry web site home page in "Broadcast Messages."

Interest Rate November 2006

Alberta Energy's interest rate for November 2006 is 7.00%.

August Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the August 2006 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$5,300,971.32	($4,658,296.98)	$642,674.34

August Penalty Charges

The revised penalty table below shows at the form level, the total penalty charges and reversals, for the August 2006 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2006/08
AC2	$6,500	($900)	$5,600
AC4	$400	($200)	$200
AC5	$600	($900)	($300)
GR2	$0	$0	$0
NGL1	$1,000	$0	$1,000
VA2	$0	$0	$0
VA3	$0	$0	$0
VA4	$100	$0	$100
Total	**$8,600**	**($2,000)**	**$6,600**

Alberta Royalty Tax Credit Program Quarterly Rate

For the fourth quarter of 2006, commencing October 1, 2006, the royalty tax credit rate will be .2500. This rate is based on a royalty tax credit reference price of $430.81 per cubic metre as set by the Department of Energy. The Alberta Royalty Tax Credit rates for the past year were:

Third Quarter, 2006	.2500
Second Quarter, 2006	.2500
First Quarter, 2006	.2500
Fourth Quarter, 2005	.2500

If you have any questions, please contact Alberta Finance, Information Services at (780) 427-3044. [Toll-free long distance is (780) 310-000-427-3044].

Gas Royalty Calculation Support

Gas Royalty Calculation staff will be available monthly to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to call Richard Stokl, Manager, Client Services (780-422-9258) or e-mail richard.stokl@gov.ab.ca two business days before the meeting date to arrange an appointment. The December through March schedule is as follows:

Where:
AMEC Place
Room 437, 801-6 Avenue SW
Calgary, Alberta
Phone: 403-297-8954
(Industry must go to the 3rd Floor Reception upon arrival to sign-in and be given a visitor tag)

When – 10 am to 3 pm
December 13, 2006
January 25, 2007
February 22, 2007
March 29, 2007

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role start date with no end date, then that BA can receive allocations from the stated start date forward.
- If a BA has a WIO role start and end date, then they can only receive allocations from the stated start date until the end date. Any allocations after the end date will be rejected.
- If a BA does not have a WIO role start date, then that BA cannot receive allocations at all.

Please contact Client Registry at (780) 422-1395 if you have any questions regarding the information supplied on this listing.

Projects/Blocks

If information is required on Projects or Blocks, please contact Isabelle Warwa at (780) 427-8952.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at (780) 422-1395.

The following is a list of struck, cancelled, dissolved, and revived clients:

Company Name	**Client ID**	**Struck Date**
933676 Alberta LTD	0D6K	November 02,2006
Canoga Resource Management LTD	0EZ5	November 02, 2006
Evinco Exploration INC	A021	November 02, 2006
Fan-C Construction LTD	0F8P	November 02, 2006
Industrial Coal and Minerals LTD	0YN7	November 02, 2006
Company Name	**Client ID**	**Cancelled Date**
Pengrowth Acquisition Corporation	A10B	November 02, 2006
Company Name	**Client ID**	**Dissolved Date**
Garfield Resources LTD	0P7B	October 31, 2006
Company Name	**Client ID**	**Revived Date**
Fairholme Resources LTD	0F8L	October 23, 2006
Harp Resources LTD	0G6J	November 10, 2006
Matrix Resources LTD	0WJ9	October 20, 2006
Universal Ford Lincoln Sales LTD	646C	November 7, 2006

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Operating Costs Subject to Recapture

Operating costs subject to recapture reports for the 2005 production year were produced effective the April 2006 billing period invoice issued in June 2006, have been issued each month since then and has been charged in the August 2006 invoice issued in October 2006.

For more information, please contact your applicable Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

Statutory Requirement and Recalculation of 2002 Royalty

A production year becomes statute barred on December 31st, four years after the end of a production year. Once a year has become statute barred, calculation or recalculation of royalty does not occur on a monthly basis.

Section 38 of the Mines and Minerals Act provides for recalculation of royalty that can be initiated in either of two ways:

a) On the department's initiative in conjunction with an audit or examination; or
b) At the request of a royalty payer.

Audits in Progress

Non-operator partners are advised that certain 2002 capital cost and custom processing adjustment factor (CPAF) and reporting discrepancy audits are currently in progress. It is anticipated that these audits may be completed before December 31, 2006. However, should circumstances require that these audits be completed in 2007, a listing of the affected EUB facilities will be included in the December 2006 Information Bulletin.

Royalty clients are also reminded that amendments received by the department in the fourth year following the production year may be subject to audit. If the amendments are received late in the fourth year and insufficient time is available for the department to commence a review of the amendments prior to the end of the year, the department reserves the right to commence the audit at the beginning of the fifth year.

If you have any questions, please contact Chris Lawton of the Compliance & Assurance group at (403) 297-6746.

Industry Recalculation of 2002 Royalty

Industry initiated royalty recalculation requests for the 2002 production year must be submitted in writing to the attention of Richard Stokl, Manager of Gas Royalty Client Services. This request must be received by the department on, or before, December 31, 2006 and it should include the following:

- Identification of the recalculation facility or facilities;
- The reason for the recalculation;
- An order of magnitude estimate, i.e. the approximate amount of the royalty impact;
- Identification of the royalty clients that may be impacted by the request;
- The time lines for recalculation preparation and submission to the Crown including a reasonable time for the Crown to review the submission; and
- Confirmation that the affected partner(s) have been notified.

If you have any questions regarding this process please contact your Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Alberta Energy Internet

Prices, Royalty Rates, and Transportation Information are available on the Alberta Energy Internet address: http://www.energy.gov.ab.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Calculation Information Bulletins and Information Letters are also available on the Alberta Energy Internet address: http://www.energy.gov.ab.ca, from "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

The Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Service teams. Listed below is the portfolio breakdown along with Client Service Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at (780) 644-1202.

Business Associate	Phone Number and E-mail Address	Team Lead
Numbered companies, A, B & L	(780) 644-1201 GRCST1@gov.ab.ca	Mary Spearing
C – G	(780) 644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	(780) 644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q – Z	(780) 644-1204 GRCST4@gov.ab.ca	Kamal Rajendra

Gas Royalty Reception: (780) 427-2962
Fax: (780) 427-3334 or (780) 422-8732
Alberta Toll Free: (780) 310-0000
Hours of operation are 8:15 a.m. to 4:30 p.m.
Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer.

Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets. You would not be entitled to information regarding business for TSP Exploration that is prior to the asset purchase.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone (403) 297-5514
Fax (403) 297-5400

Calgary Information Centre

300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone (403) 297-6324
Fax (403) 297-8954

Alberta Royalty Tax Credit Information

Alberta Finance, Tax and Revenue Administration
Tax Services
Telephone: (780) 427-3044
Alberta Toll Free: (780) 310-0000
Fax: (780) 427-5074
For further information, please contact Tax Services at (780) 427-9425.

Deen Khan
Director, Gas Royalty Calculation
Gas Development

Attachments

2006 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butanes ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	9.52	9.56	9.56	9.33	9.11	9.10	9.14
FEB	7.38	7.36	7.36	7.58	7.58	7.58	7.59
MAR	6.47	6.46	6.46	6.67	6.71	6.74	6.76
APR	6.18	6.17	6.17	6.31	6.31	6.36	6.36
MAY	5.71	5.70	5.70	5.77	5.74	5.76	5.77
JUN	5.29	5.26	5.26	5.57	5.64	5.67	5.70
JUL	5.22	5.19	5.19	5.48	5.54	5.57	5.58
AUG	5.84	5.81	5.81	6.06	6.10	6.13	6.15
SEPT	5.12	5.12	5.12	5.14	5.09	5.12	5.13
OCT							
NOV							
DEC							

Natural Gas and NGLs Select Prices for 2006	
Commodity	2006
New Methane	1.419 $/GJ
Old Methane	0.418 $/GJ
New Ethane	1.419 $/GJ
Old Ethane	0.418 $/GJ
Propane	1.419 $/GJ
Butanes	1.419 $/GJ
Pentanes plus	50.73 $/m3

Royalty Factors for Pentanes plus		
	Base	Marginal
New Pentanes	22	35
Old Pentanes	22	50

DETAIL OF THE SEPTEMBER 2006 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	5.436	5.459	5.340	5.235	5.238	5.228
Deductions: Intra – Alberta Transportation	0.229	0.244	0.139	0.098	0.075	0.057
Marketing Allowance	0.012	0.012	0.012	0.012	0.012	0.012
Price Before Pipeline Factor	5.195	5.203	5.189	5.125	5.151	5.159
Pipeline Fuel/Loss Factor	.990	.990	.990	.990	.990	.990
Price before Special Adjustment	5.144	5.153	5.139	5.076	5.100	5.109
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	5.144	5.153	5.139	5.076	5.100	5.109
Amendments: Carry forward (from previous RP month)	0.004	-0.001	0.001	0.001	0.002	0.001
Prior Period Amendment Adjustment (current RP month)	-0.026	-0.032	0.003	0.012	0.015	0.016
Calculated RP after Amendments	5.122	5.120	5.143	5.089	5.117	5.126
AUGUST 2006 Reference Price	**5.12**	**5.12**	**5.14**	**5.09**	**5.12**	**5.13**
Difference = value carried forward to next RP month	0.002	0.000	0.003	-0.001	-0.003	-0.004
Adjusted IATD (before Prior Period Amendments)	n/a	0.241	0.137	0.097	0.075	0.057
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	n/a	0.241	0.137	0.097	0.075	0.057

2005 Weighted Average Reference Price ($/GJ)
7.935

2005 Weighted Average OMAC ($/GJ)
0.023

2006
NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Par Price ($/GJ)	Propane Floor Price ($/m3)	Butanes Reference Price ($/m3)	Butanes Par Price ($/GJ)	Butanes Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	9.33	9.33	289.22	9.11	240.07	394.52	9.10	329.84	484.39	477.02	27.53
FEB	7.58	7.58	248.16	7.58	213.28	370.63	7.58	279.57	468.40	441.89	29.48
MAR	6.67	6.67	254.40	6.71	213.86	362.89	6.74	272.66	468.85	457.27	31.39
APR	6.31	6.31	286.26	6.31	248.88	390.67	6.36	290.57	545.33	524.82	25.41
MAY	5.77	5.77	279.81	5.74	247.11	376.44	5.76	283.32	529.03	507.26	24.31
JUN	5.57	5.57	287.72	5.64	258.60	377.94	5.67	295.08	557.91	516.67	21.78
JUL	5.48	5.48	313.36	5.54	281.70	402.10	5.57	315.61	564.17	538.62	18.77
AUG	6.06	6.06	305.03	6.10	275.34	402.10	6.13	317.45	530.10	511.93	14.09
SEPT	5.14	5.14	269.07	5.09	240.91	366.43	5.12	268.30	443.64	429.71	16.45
OCT											
NOV											
DEC											

ANNUAL SULPHUR DEFAULT PRICE				
2001	2002	2003	2004	2005
$0.28	$6.74	$30.97	$31.98	$33.98

2006
NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANES (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW. (per m3)
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	-0.90	13.92	10.05	18.08	18.72	-1.58	-33.18	-18.57	17.78	14.75	35.26	16.39	15.50
FEB	24.88	25.25	34.62	26.47	10.17	-2.24	-57.23	-19.17	18.42	13.68	31.79	18.91	15.50
MAR	14.23	10.00	32.47	4.43	12.33	6.56	3.05	-2.25	20.08	16.58	22.76	19.67	15.50
APR	16.82	16.81	36.92	26.20	8.13	4.05	4.42	3.86	18.80	24.73	22.81	27.82	15.50
MAY	21.44	17.83	34.47	26.88	7.50	0.28	-5.71	1.91	17.91	17.74	17.30	23.36	15.50
JUN	43.47	23.21	58.72	48.53	11.04	8.25	3.62	3.89	39.43	25.73	31.26	24.21	15.50
JUL	25.15	20.49	48.28	19.48	14.52	5.93	12.23*	6.56	31.03	17.24	30.26	23.09	15.50
AUG	22.34	13.57	22.42	12.02	6.13	-0.40	-13.90	4.17	5.48	6.47	11.26	14.65	15.50
SEPT	7.15	14.00	37.82	22.86	15.20	-0.29	11.19*	-0.03	2.90	5.70	0.43	12.06	15.50
OCT													
NOV													
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butanes obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

* Current month calculated allowance is based on an estimate.

Note: For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS

NGL REFERENCE PRICES	SEPTEMBER 2006		
	Propane	*Butanes*	*Pentanes*
Price before amendments	269.073506	366.431619	443.639243
Opening Rollover (from prior business mth)	-0.002710	0.002601	-0.001637
Prior Period Amendment Adj. (NGL-1)	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	0.000000	0.000000	0.000000
Published Reference Price	**269.07**	**366.43**	**443.64**

TRANSPORTATION ALLOWANCES	SEPTEMBER 2006											
	Pentanes Plus				Propane and Butanes				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	-0.003260	0.000382	0.000729	-0.002955	0.003582	-0.003898	0.003128	-0.000522	-0.000811	0.000940	-0.002177	-0.003304
Prior Period Amendment Adj. (NGL1)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Total Amendment Effect	-0.003260	0.000382	0.000729	-0.002955	0.003582	-0.003898	0.003128	-0.000522	-0.000811	0.000940	-0.002177	-0.003304
Calculated Transp. Differential	7.148977	14.000720	37.815935	22.865164	15.197102	-0.286425	11.185526*	-0.031104	2.900559	5.696905	0.435766	12.067420
Calculated Transp. Differential after Total Amendments	7.145717	14.001102	37.816664	22.862209	15.200684	-0.290323	11.188654*	-0.031626	2.899748	5.697845	0.433589	12.064116
Published Transportation Allowance	**7.15**	**14.00**	**37.82**	**22.86**	**15.20**	**-0.29**	**11.19***	**-0.03**	**2.90**	**5.70**	**0.43**	**12.06**

*Any estimates represented by (*) are calculated as the weighted average of the other regions for the same spec product transportation allowance, since the region is zero. The weightings are based on the previous year's production.

2006
ROYALTY RATES

MONTH	METHANE-OLD (% per GJ)	METHANE-NEW (% per GJ)	ETHANE - OLD (% per GJ)	ETHANE - NEW (% per GJ)	PROPANE (% per m^3)	BUTANES (% per m^3)	PENTANES – OLD (POL) (% per m^3)	PENTANES - NEW (PNE) (% per m^3)
JAN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.02226	33.61748
FEB	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.78553	33.50757
MAR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.89365	33.55777
APR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.29347	33.74340
MAY	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.19978	33.69990
JUN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.25078	33.72358
JUL	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.36282	33.77559
AUG	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.22532	33.71176
SEPT	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.69442	33.46527
OCT								
NOV								
DEC								

Value of Vertical Benefit

Vertical depth	Cumulative Value	Incremental Value
(metres)	($000)	($/metre)
2500	0	1000
3000	500	1000
3500	1000	1000
4000	1500	1300
4500	2150	1300
5000	2800	1600
5500 or deeper	3600	